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Limitations of Using Smart Wells to Achieve Waterflood Conformance in Stacked Heterogeneous Reservoirs: Case Study from Piltun Field

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Abstract

The use of smart completion with downhole fluid control through Inflow Control Valves (ICVs) has been extensively described in the literature for balancing the water injection profile and improving the sweep efficiency in commingled water injection. This paper describes the limitations of such a system in ensuring zonal distribution of water in stacked, highly heterogeneous reservoir systems.

Voidage replacement and pressure maintenance requirements necessitate waterflood under fracturing conditions in the four stacked reservoirs (Zone 1 to Zone 4) in Piltun field, offshore Sakhalin Island, Russia. These reservoirs are heterogeneous with differences in their permeability and fracture gradient. Consequently, smart injectors with four ICVs were planned to maintain the desired injection allocation in these reservoirs. The initial injectivity of these wells was extremely low with all of the injected water going to the deepest zone (Zone 4). An expensive pump upgrade improved the overall injectivity, with drastic changes in the distribution of the injected water amongst the reservoir layers. Contrary to performance prior to pump upgrade, the shallowest zone (Zone 1) emerged as the dominant receiver of injected water. Overall, the zonal distribution of water remained a problem with little success in injecting water in the remaining two zones (Zone 2 and Zone 3). Very limited improvement in the water distribution was obtained by manipulating the ICV valves.

Sector modeling was taken up for the injection wells to understand the injection behavior. Modelling results show that after the pump upgrade, fracturing was initially achieved in all zones, although sustained fracture opening and propagation was only possible in Zone 1, the reservoir with better flow properties and reasonably low fracture gradient. The other zones gradually reverted back to injection under matrix conditions with time. The additional pressure drop created by the flow control device is not sufficient to choke back the major zones and achieve sustained fracture growth and water injection in the minor zones in Piltun field. The results demonstrate that the use of intelligent completion for waterflood conformance can be limited by large stress and permeability contrast.

Introduction

Water injection is one of the most common Improved Oil Recovery (IOR) methods in use around the globe. It helps in maintaining reservoir pressure and improves hydrocarbon sweep. Simplicity of execution and low operational costs makes it the IOR method of choice. Waterflood under matrix conditions leads to rapid loss of injectivity due to several reasons [1] and [2]. This necessitates water injection under fracturing conditions for majority of waterflood projects, well slot constrained offshore operations in particular. During fractured injection, water is injected above the minimum horizontal stress to induce fractures in the rock. The fracture face provides greater area for leakoff, which results in improved injectivity and reduces the water quality requirements compared to matrix injection.

In case of multiple, vertically stacked reservoirs, it is desirable to waterflood several reservoirs from a single well (commingled water injection) to reduce the well count and improve the economics of the waterflood project. However, proper distribution of the injected water (concomitant to the voidage replacement requirements) across these reservoir layers must be ensured.

Such stacked reservoirs present unique challenges during waterflood under fracturing conditions. In some cases there is tendency for preferential fracture initiation and growth in select reservoir layers (low fracture propagation pressure) that may jeopardise the objectives of commingled water injection. Achieving fractured water injection in multiple stacked reservoirs requires the bottomhole injection pressure to be high enough to exceed the highest of the initiation pressure amongst all the target reservoir layers [3]. Therefore, additional reservoir-wise control is needed on the BHP to regulate the fracture growth and dimensions in the individual reservoir layers.

Smart completions, equipped with downhole sensors and valves provide such capabilities [4]. Reservoir wise control on the BHP can influence fracture growth and consequently the fluid flow into the individual layers [5]. Smart completions have been used in the past to achieve desired inter-reservoir distribution of the injected water [6], [7] and [8]. They are seen as particularly effective in the presence of moderate contrast in geomechanical and dynamic properties among the different layers [9]. This paper aims to show limitations of such an approach.

Field Introduction

The Piltun field forms part of the Piltun-Astokhskoye (PA) structure, an 11 km by 5 km anticline, containing stacked oil and gas accumulations in a sequence of shallow marine reservoirs of Late Miocene age at depths between 1600 and 2100 m subsea. The PA field was discovered in 1982, although the Piltun element of the structure was not drilled until 1987.

The formation contains normally pressured reservoir layers with net thickness ranging from 1 m to 29 m. These can be grouped into four main reservoirs, enumerated as Zone 1 to Zone 4. An east-west cross-section across the field is shown in Figure 1. These reservoirs show a wide range of flow properties (Table 1) with permeability varying between 1 mD up to several Darcy (so-called ″superfacies″) in some layers. The porosity varies from 19% to 26%. Piltun fluid properties do not vary significantly with depth and temperature. The reservoirs contain 32°API crude with solution GOR of 540 scf/stb. All reservoirs have primary gas caps, with saturation pressures between 180 and 220 bars.

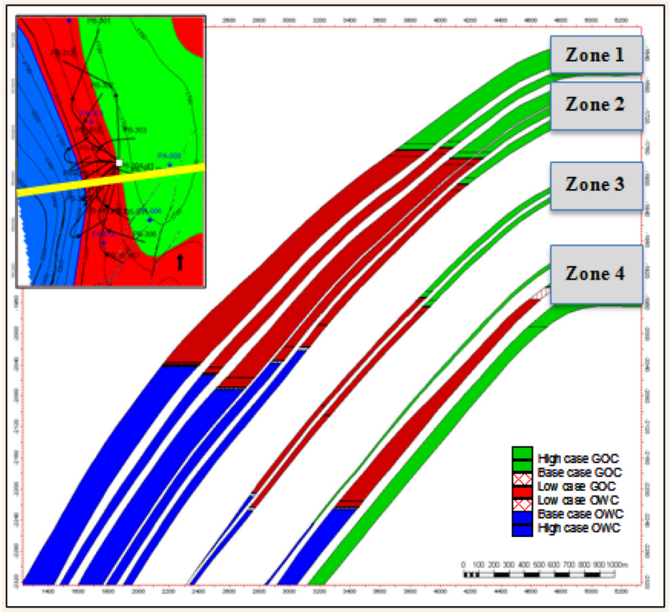

Figure 1—East-west cross section across the Piltun field

Table 1—Average layer wise reservoir properties

Zone	NTG (fraction)	Gross thickness (m)	Res Porosity (fraction)	GeomMean Perm (mD)	HC Pore Vol. Height (m)
Zone 1	0.9	30	0.22	8	3.0
Zone 2	0.8	21	0.21	4	1.2
Zone 3	0.8	27	0.20	3	0.9
Zone 4	0.9	35	0.23	75	3.0

Injection Background

Injection System Design The Piltun field was brought onstream in late 2008. The first phase of field development (2008 – 2009) involved construction of the first five oil producers and the first water injector. Commingled water injection in the four reservoir zones under fracturing conditions was chosen to enable higher injection volumes per well, thus freeing up the platform well slots for oil producers.

Water injection for the first few years was planned with seawater, but with increasing water cut during field life, the produced water was to be blended with seawater and used for injection. In case of matrix injection, this would have led to rapid injectivity decline, due to decreasing water quality and increasing injection temperature with time [10]. A brief description of the water injection and produced water handling facility (Figure 2) has been included in Appendix 1.

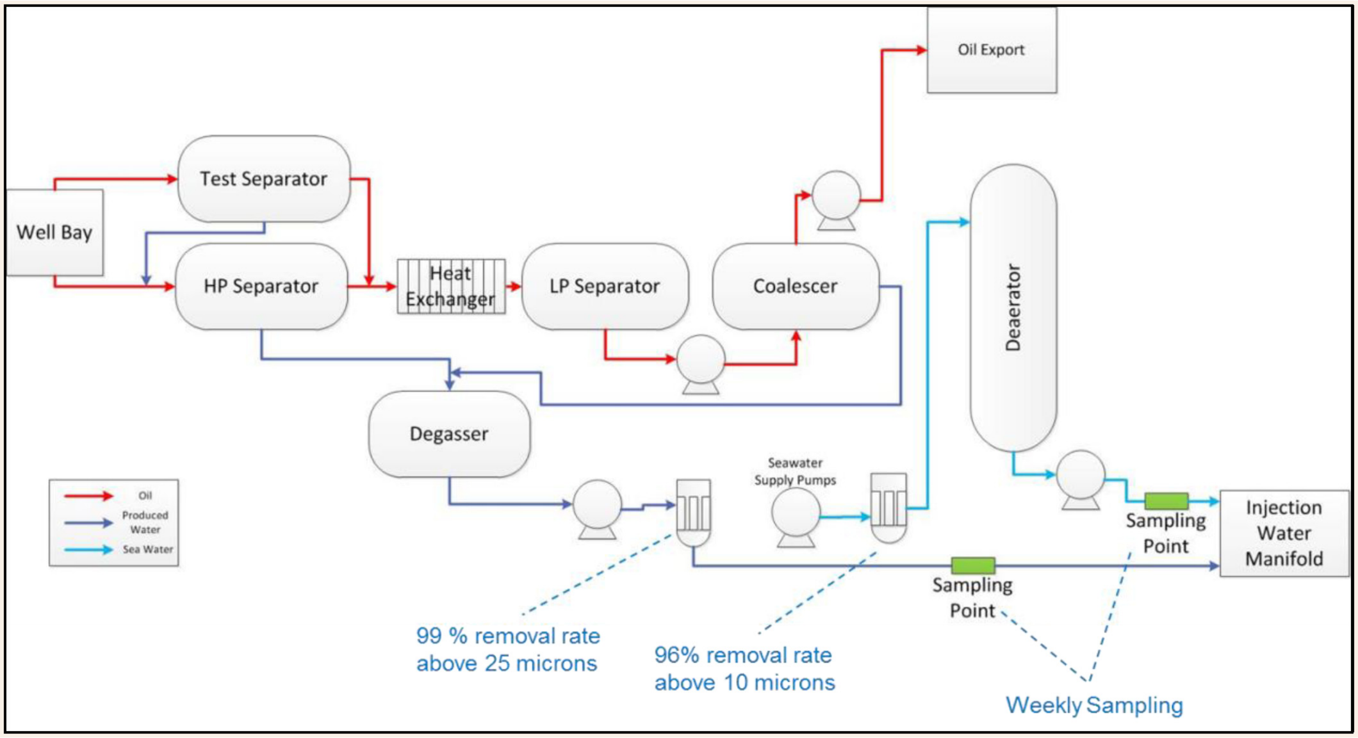

Figure 2—Piltun water injection system

In the case of commingled water injection in multiple layers, fracture would be initiated in the reservoir with the lowest fracture gradient or the minimum total horizontal stress. In the absence of downhole selectivity, the reservoir with the lowest fracture gradient would effectively control the Bottom Hole Pressure (BHP) during injection. Fractured water injection in the other reservoirs would not be realized because any increase in the injection rate would be accommodated by increase in the size of the existing fracture without significant change in the bottomhole injection pressure.

Moreover, higher injected water volume in the layer containing induced fractures may reduce the fracture gradient further due to thermal effects[1], thus enabling continual fracture growth. The other layers, in the absence of any fracturing, would be injecting under matrix conditions and will gradually plug up with injected solids. This self-supported cycle would lead to an increasingly skewed water distribution with more and more of the injected water progressively going to the zone with lowest fracture gradient.

Due to known permeability and stress contrast in Piltun reservoirs, the need to have some form of downhole selectivity in the completions was realized during the design phase. Smart completions, with surface controlled zonal flow control valves, were chosen as the completion concept instead of wireline adjustable chokes that would have required frequent well entries.

Role of ICVs in Regulating Fracture Dimensions Six out of seven injection wells in Piltun field are commingled multi-zone injectors with downhole smart control. Each well consists of four zones isolated by packers (Appendix 2). The tubing communicates with the annulus through ICVs. The valves are accompanied by pressure and temperature gauges on both the tubing and the annulus side. Five hydraulic control lines control the valves of all 4 zones, and the gauges and valve positions are monitored with two electrical cables.

[1] Thermal stresses depend on the temperature difference between the injected water and reservoir and on the reservoir rock mechanical and thermal properties. In case of the injection of cold seawater in higher latitudes, the reduction in the Shmin can be several tens of bar.

The valve features eight positions, including fully-open, fully-closed and six intermediate choking positions. Each of these positions results in a different flow area, and hence a different flow rate. This section explains the functioning of the multi-zone ICVs to achieve fracture growth (and thus flow rates) in poor, low-perm, high fracture gradient zones.

The flow rate across the ICV is given by the equation below:-

$$Q = 10288 \frac{C_v A_c}{B_o} \sqrt{\frac{P_{TBG} - P_{WF}}{\rho}}$$

where,

Q = Flowrate, stb/day
C_v = Choke Discharge coefficient (usually between 0.75 and 0.95)
A_c = Choke Area, inch^2
B_o = Formation Volume Factor, rbbl/stb
P_{WF} = Flowing Bottomhole pressure (Upstream Choke Pressure), psia
P_{TBG} = Tubing Pressure (Downstream Choke Pressure), psia
ρ = Liquid Density, lb/ft^3

The flow rate across a flow control valve, and consequently into a specific zone, is directly proportional to the flow area of the valve and square root of the differential pressure across the valve. Zones with a low fracture gradient would have a low P_{WF} and thus high differential pressure and injectivity. The ICV can be used to limit the flow across such zones (with high injectivity) by reducing the choke area (lower choke position).

For a fixed water injection rate, lower flow across the high injectivity zones would increase the BHP. It is desired that the injection BHP (P_{TBG}) becomes high enough for fracture breakdown and fracture propagation in zones with higher fracture gradient (Table 2). Flow across such poor zones can be aided by ensuring maximum possible flow area across the ICVs (fully open choke).

Table 2—Well-2 layer wise rock properties

Layer	Perforation Interval (m)	Pore Pressure (psi)	Young's Modulus (Mpsi)	ShMin Gradient (psi/ft)	ShMax Gradient (psi/ft)
Zone 1	10	2800	0.58	0.81	1.02
Zone 2	20	3220	0.70	0.80	0.98
Zone 3	30	3410	0.97	0.89	1.08
Zone 4	10	3655	0.99	0.69	0.85

Thus, in the case of multi-zone ICV completion, choking back the rich zones provides an effective way to

1. Limit fracture growth and flow in the rich zones (low fracture gradient and high permeability).
2. Increase injection BHP for fracture breakdown and propagation in poor zones (high fracture gradient and low permeability).

Hence the ICVs provide an effective way to control the fracture growth in the different reservoir layers. Optimized choke positions can be used to regulate the fracture size or the 'leak off' area in each of the reservoir zone to get desired distribution of water.

Injection Performance Despite significant work in the design phase, the entire injection system proved to be inefficient because the reservoirs in the aquifer zone were found to have higher fracture gradient than initially believed. The discharge pressure (145 bars) of the injection pump was designed for fracture gradient of 0.7 psi/ft to 0.8 psi/ft, based on fracture gradient in the producers. Injection tests performed with a cement pump demonstrated that the fracture gradient of the reservoirs ranged from 0.69 psi/ft for the lowest layer (Zone 4) to 0.89 psi/ft. for Zone 3 (Figure 3). This required higher injection pressures to attain waterflood under fracturing condition than the water injection pumps could deliver. At the end of 2011, the field-wise voidage replacement ratio was only 9%.

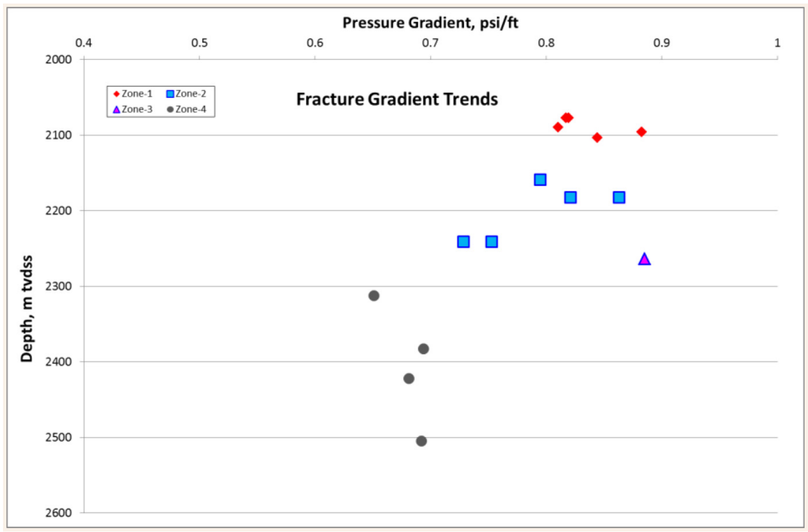

Figure 3—Fracture closure pressure (Piltun injector wells)

The water injection pumps were upgraded in 2012. This new system was rated to deliver a much higher discharge pressure (277 bar) than the previous system (145 bar). During the period of pump upgrade, the field did not receive any water injection (May 2012-Dec 2012). The high discharge pressure pumps enabled a significant improvement in the total field injectivity. The total injection rate almost doubled from 20,000 bwpd to 40,000 bwpd (Figure 4).

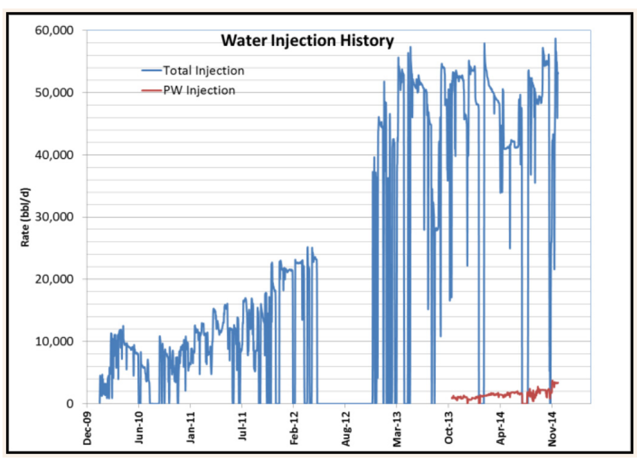

Figure 4—Piltun water injection history

In October 2013, mixed water injection was started, mixing produced water with seawater. The water production rates, as of end of 2014, were low in comparison to the total injection, and constituted less than 10% of the total injection rate. This dilution, along with surface filters, kept the concentration of contaminants in the produced water within safe limits. By the end of 2015, the field had 7 water injectors, with a combined injection rate of 50,000 bwpd.

The zone wise Voidage Replacement Ratio (VRR) for the field is shown in Figure 5. The plot shows the disparity between the water requirement for unity VRR and the actual water injection volumes in the different layers of the field. The bottommost zone (Zone-4) is taking more water than VRR requirements (VRR > 1) whereas the injection targets are not being met in all other zones.

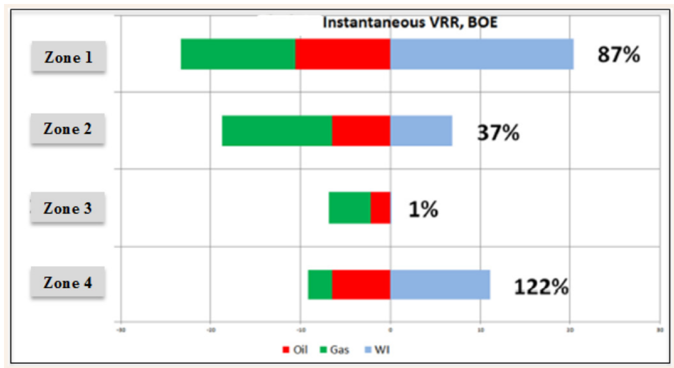

Figure 5—Instantaneous voidage replacement ratio per layer (2014)

This paper focuses on the injection behavior of Well-2, one of the few injectors completed in all the four reservoir zones with a relatively long injection history (water injection since February 2010). Table 3 summarizes the reservoir properties in the vicinity of Well-2. Zone-1 and Zone-4 are referred as the major zones as they are the primary injection targets. The historical water injection performance for Well-2 is shown in Figure 6. The figure also shows the zone wise split of the injected water inferred from the downhole gauges.

Table 3—Well-2 layer wise reservoir properties

Layer	Perm (mD)	Gross Thickness (m)	kH (mD.m)
Zone 1	54	25	1350
Zone 2	10	37	370
Zone 3	1	12	12
Zone 4	20	12	240

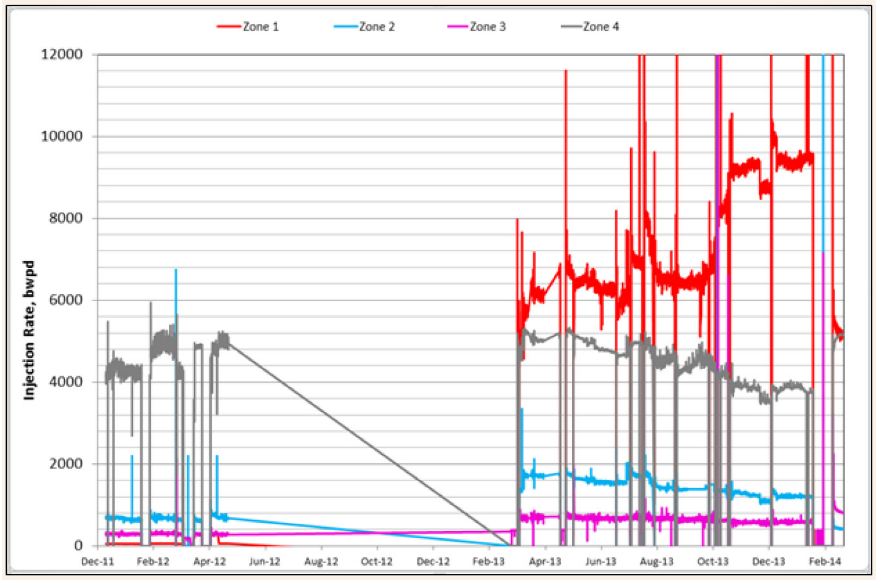

Figure 6—Well-2 layer wise injection history

The injection behavior of Well-2 is characterized by:

1. Low cumulative injection rate of ~ 6,000 barrels of water per day (bwpd) prior to the booster pump upgrade.
2. Water injection during this period was primarily in the deepest zone (Zone 4), with little water going into the other major layer – Zone 1. The minor layers, Zone 2 and Zone 3, were receiving less than 200 bwpd each.
3. The zonal ICVs were set to favour the major layers, with both Zone 1 and Zone 4 at position 7 (fully open) and Zone 2 and 3 at position 6 and 4 respectively (Figure 7).

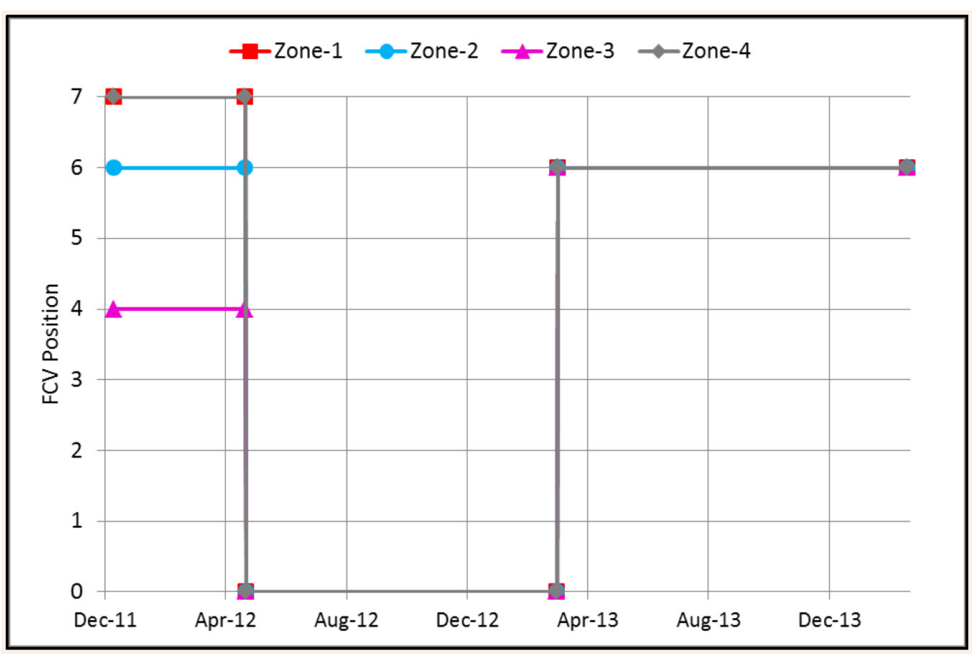

Figure 7—Well-2 ICV positions

4. Cumulative water injection rate increased almost three-fold post pump upgrade to 15000 bwpd.
5. Drastic changes in the zonal distribution of the injected water were seen post pump upgrade. Contrary to previous years, Zone 1 emerged as the dominant receiver of the injected water. Significant water was still being injected into Zone 4 with some improvement in the injectivity of the minor layers.
6. The skewness of the water distribution was seen to increase with time with a greater fraction of the injected water going into Zone 1. The injectivity of the other layers show progressive decline since March 2013.

Modelling Work for Future Injectors

This study was triggered by unsatisfactory waterflood conformance in Piltun field. The objective of the modeling exercise was twofold;

a. Understand the historical waterflood performance including zonal distribution of the injected water post and pre pump upgrade,
b. Optimize the ICV choke positions to get the desired water distribution.

A dedicated sector model was built for injector Well-2 to understand the injection behavior and smart control. A reservoir simulator capable of including the ICV component was chosen for simulation work. The simulation grid around the well was sufficiently refined to accurately capture fracture growth. The full-field model of the field was used to populate the petrophysical, geomechanical and thermal properties.

A detailed well description including survey data, equipment detail, tubulars and the ICVs, was included in the sector modeling exercise. The ICVs were modeled as an orifice, the different flow positions captured by changing the flow area.

A fracture initiation seed was placed in each of the zones, assuming growth of a single fracture per perforation interval. For Zone 2 and Zone 3, which have two completed intervals, an initiation point was assumed in each. A 3D fracture model was selected for simulation that computes the fracture dimensions as a function of time. The fracture model is based on elastic fracture opening and propagation depending on the rock strength and stiffness. The fracture model considers flow within the fracture and leakoff from the fracture face. It also includes the effects of stress changes due to injected fluids (thermal and poro-elastic backstresses). The fracture model transitions from propagating to non-propagating state by closing its width, thereby reducing conductivity and injection at the fracture peripheries rather than receding the parameter.

The maximum horizontal stress in the field is oriented ~70 degrees from north, and its relative orientation to the well azimuth has been captured in the model. The key geomechanical inputs for the different reservoir zones are summarized in Table. Of particular interest is the significantly low fracture gradient for Zone 4, despite being the deepest zone. The fracture gradient of the intra-reservoir shales was assumed to be 0.9 psi/ft.

A detailed schedule mimicking historical injection data was included in the simulation. The well was run under an arithmetically averaged BHP value for discrete periods. A constraint of 15,000 bwpd was applied on the total injection rate based on historical injection.

Results

Understanding Historical Injection The model was successful in replicating the historical injection, in particular with regards to the zonal injection in the major layers (Figure 8). Post pump upgrade, Zone 1 shows gradual increase in injection and Zone 4 shows similar decline, albeit with about 1,000 bwpd of deviation from measured rates. The model, however, over predicts the injection into the minor layers, primarily due to a constant value of injection assumed for the entire injection period. This leads to a superficial peak in the injection rate for the minor layers (Zone 2 and Zone 3) just after pump upgrade.

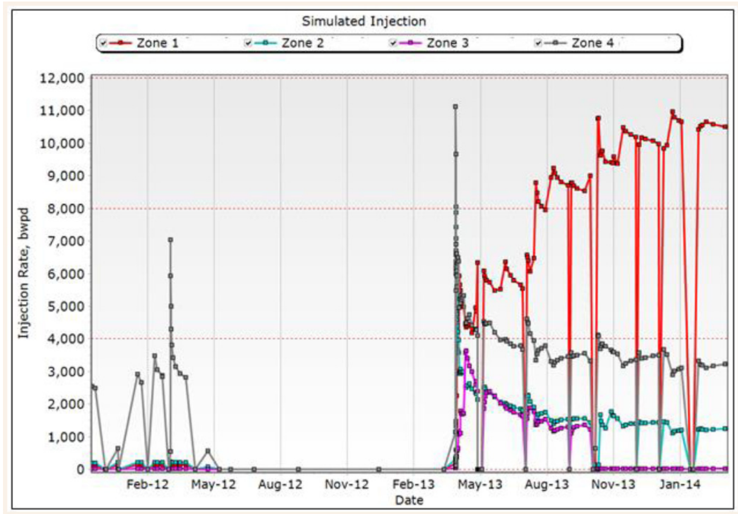

Figure 8—Well-2 simulated injection

High injectivity is expected in layers with greater area for leak off i.e. fracture surface area. Therefore, the fracture half-length computed by reservoir simulator was analysed to understand the injection behavior. The fracture half-length for the different reservoir layers is shown in Figure 9. Prior to pump upgrade, fracturing was attained only in the bottommost zone that has the lowest minimum horizontal stress amongst all reservoir zones. The other zones were injecting under matrix conditions. This explains the high injectivity of Zone 4.

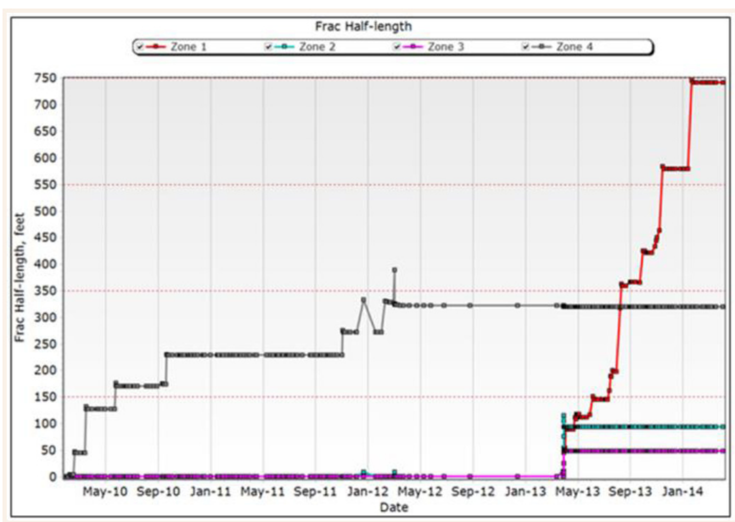

Figure 9—Well-2 fracture half-length with time

Post pump upgrade (May 2013), fracturing is attained in all the zones. However, sustained fracture growth is seen in Zone 1 due to reduction in fracture propagation pressure by thermal cooling. This zone has high permeability compared to the other layers that leads to low poro-elastic backstress. Despite fracture initiation in other zones, sustained fracture propagation (vis-à-vis Zone 1) is now possible due to higher fracture gradient and poro-elastic back stresses. Fracture shrinkage and closure is responsible for gradual decline in the injectivity of the other layers with time. The reservoir simulator models fracture shrinkage and closure by reducing the fracture width to zero instead of reducing length. Hence, Figure 9 doesn't show any reduction in the fracture lengths of the other zones with time.

Manipulating FCVs for Desired Water Distribution The model was subsequently run with the major zones (Zone 1 & Zone 4) choked back with their ICVs choked to position 1 from position 6 (historical injection). This reduced the injection rate in Zone 1 to ~ 3000 bwpd, with little change in the injection rate into Zone 4 (Figure 10). The increase in the injectivity of Zone 2 and Zone 3 is small. Overall, the total cumulative injection in the well decreased from 15,000 bwpd to 10,000 bwpd (Figure 11). Hence, by choking back the major zones the total well injectivity reduces without significant improvement in the injectivity of the minor layers.

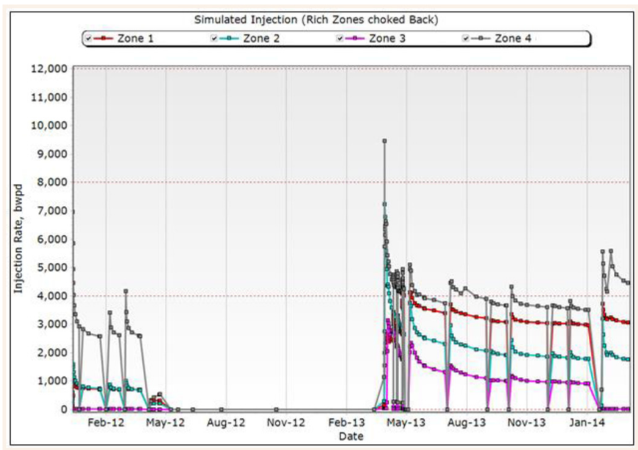

Figure 10—Well-2 injection, with major layers choked back

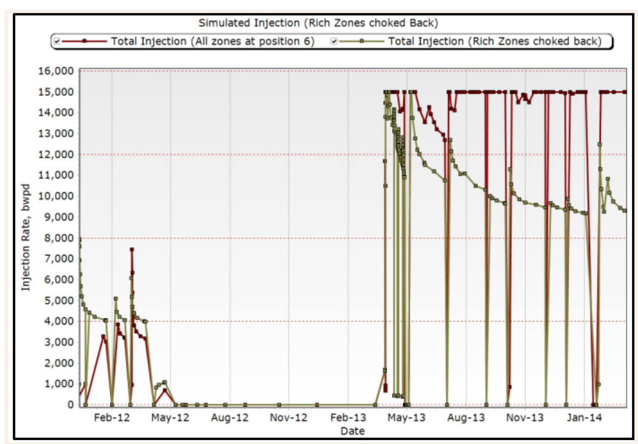

Figure 11—Well-2 total injection rate comparison

Commingling of Similar Zones This section looks at the performance of dedicated injectors for the two major (Zone 1 and Zone 4) and the two minor zones (Zone 2 and Zone 3). The simulation run with only the minor layers perforated shows that (Figure 12) the injectivity of these layers is much better without the competing major layers.

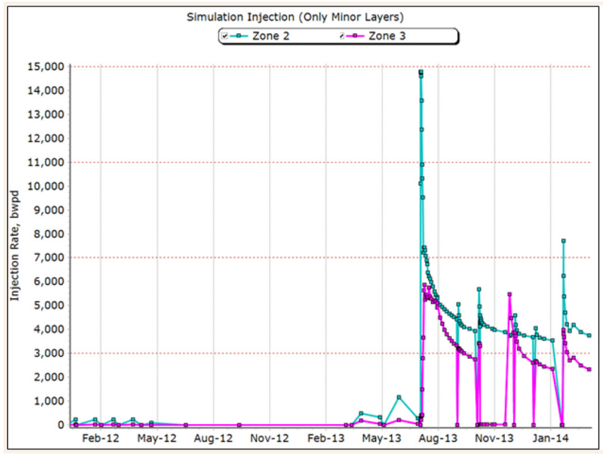

Figure 12—Well-2 simulated injection – only minor layers

The fracture growth in these layers mirrors the rates, with longer fractures achieved (Figure 13).

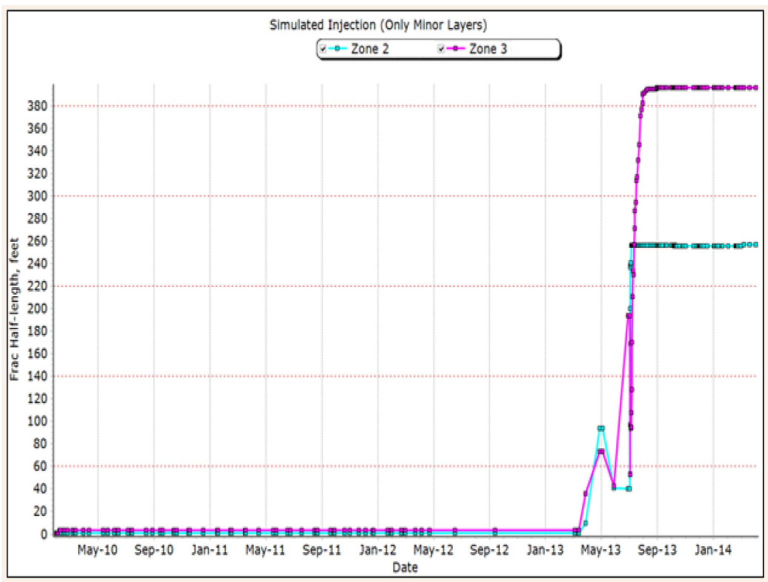

Figure 13—Well-2 Fracture Half-length– only minor layers

Similarly, better control is achieved for the major zones in case of dedicated injectors. The distribution of the injection water can be effectively reversed by choking back Zone 1 (Figure 14, 15). This effect is also seen in the fracture growth pattern (Figure 16, 17).

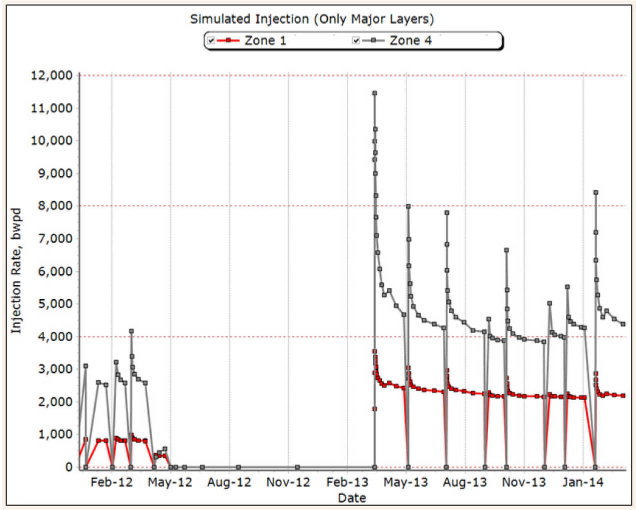

Figure 15—Well-2 simulated injection – only major layers, with Zone 1 choked back

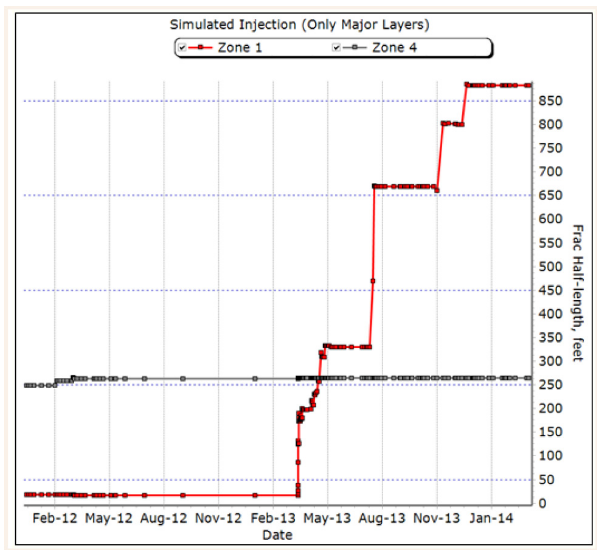

Figure 16—Well-2 fracture half length– only major layers

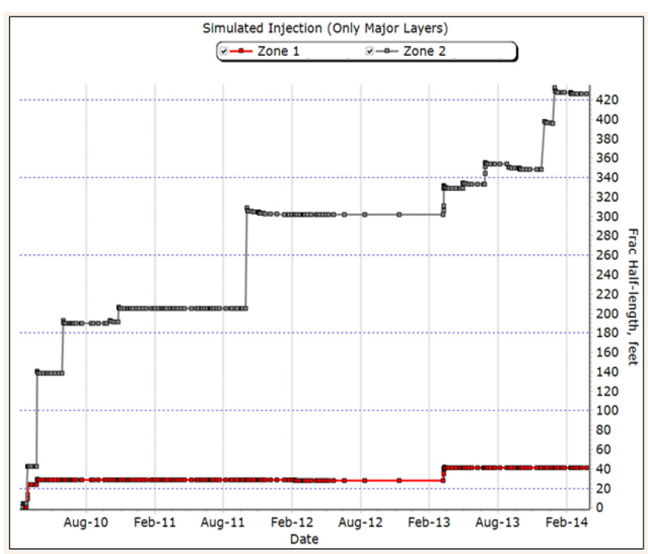

Figure 17—Well-2 fracture half length– only major layers, with Zone 1 choked back

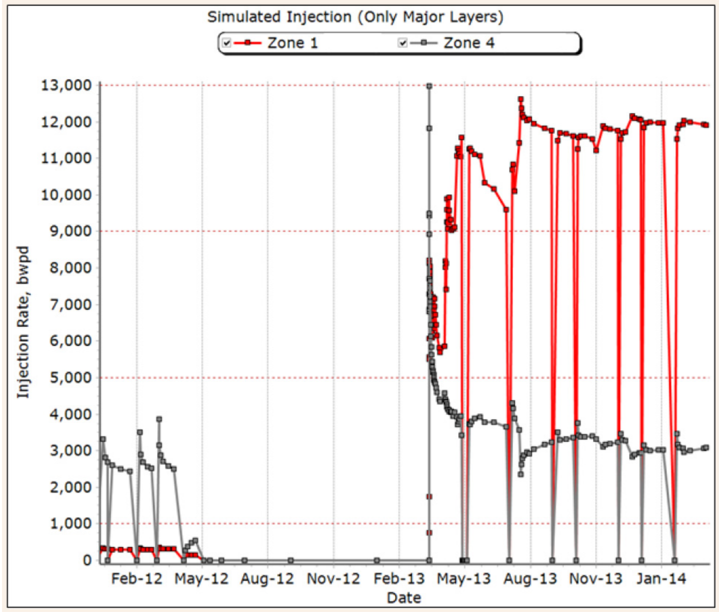

Figure 14—Well-2 simulated injection – only major layers

These results demonstrate that the ICVs are more effective in controlling flow if the layers have similar flow and geomechanical properties.

Conclusion

It can be concluded that in multi-layer commingled, fractured injection, zonal control may be difficult, even with smart completions, if the different layers have drastic differences in their flow and reservoir properties. In case of Piltun field, the effectiveness of ICVs for inter-zonal distribution of the injected water is limited by high contrast in minimum principal stress and permeability. Commingling among reservoirs with similar properties may be considered to attain the desired voidage replacement requirements.

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Nomenclature

ICV = Inflow Control Valve
NTG = Net to Gross
mD = milliDarcy
BHP = Bottom Hole Pressure
bwpd = Barrels of water per day
Q = Flowrate, stb/day
C_v = Choke Discharge coefficient (usually between 0.75 and 0.95)
A_c = Choke area, inch^2
B_o = Formation volume factor, rbbl/stb
P_{WF} = Flowing Bottomhole pressure (upstream choke pressure), psia
P_{TBG} = Tubing Pressure (downstream choke pressure), psia

ρ	=	Liquid Density, lb/ft^3
Sh_{min}	=	Minimum Horizontal Stress
S_v	=	Overburden pressure
P_o	=	Pore Pressure

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Appendix 1

Facilities Description

The water injection system consists of the produced water treatment system, the seawater treatment system and the high pressure injection pumps. A schematic of the system is shown in Figure 2. Produced water from the Produced Water Injection Booster Pumps is combined with the discharge line of Seawater Injection Booster Pumps (deaerated seawater) before entering HP Water Injection Pumps. The discharge pressure of Produced Water Injection Booster Pumps is greater than the discharge pressure of Seawater Injection Booster Pumps to ensure that produced water is preferentially pumped into the manifold. The control system within the seawater injection system automatically selects the produced water stream as the preferred injection water.

On exiting the deaerator, the treated seawater is directed to the suction of Seawater Injection Booster Pumps. These pumps provide sufficient head to meet the HP Water Injection Pumps suction requirements. To prevent backflow of produced water through the Water Injection System during normal operation, non-return valves have been installed in each Booster Pump discharge line. From the booster pumps, the treated seawater is discharged to the suction lines of High Pressure Water Injection Pumps.

The injection water stream is designed for a combination of 120,000 bwpd of deaerated seawater and 15,000 bwpd of produced water. There is a project planned to increase the produced water handling capacity to the nameplate capacity of 25,000 bwpd initially and if required at a later stage (Phase II) to 40,000 bwpd, but timing of this is based on the actual produced water volumes. The HP Water Injection Pumps each have a rated capacity of 67500 bwpd and are designed to provide an injection pressure of 330 barg upstream of the Water Injection Well choke valves and 310 barg downstream at the Wellhead. The two pumps are designed for 50% duty, having a normal suction pressure of 5 barg.

The HP Water Injection Pumps feed two injection manifolds, North side and South side. Each manifold has eight take-offs to individual injection wells and include high pressure isolation valves to ensure the safe maintenance of pumps and wells without complete shutdown of all water injection. From the manifolds, injection water is directed to the Injection Wells via Choke Valves and Xmas trees. The flow of Injection Water to each well is controlled by manual adjustment of the choke valve.

Appendix 2

Piltun Typical Injector Completion Diagram